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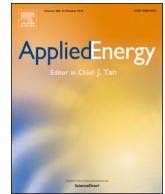
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# Power-to-gas in electricity markets dominated by renewables

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## HIGHLIGHTS

- Power-to-gas plants are not profitable under current market conditions.
- There are currently not enough hours with sufficiently low electricity prices.
- To become profitable, power-to-gas plants need higher revenues and lower costs.
- An optimistic future scenario shows that power-to-gas plants can become profitable.

## ARTICLE INFO

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Power-to-gas  
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Hydrogen  
Willingness to pay

## ABSTRACT

This paper analyses the feasibility of power-to-gas in electricity markets dominated by renewables. The business case of a power-to-gas plant that is producing hydrogen is evaluated by determining the willingness to pay for electricity and by comparing this to the level and volatility of electricity prices in a number of European day-ahead markets. The short-term willingness to pay for electricity depends on the marginal costs and revenues of the plant while the long-term willingness to pay for electricity also takes into account investment and yearly fixed operational costs and therefore depends on the expected number of operating hours. The latter ultimately determines whether or not large-scale investments in the power-to-gas technology will take place.

We find that power-to-gas plants are not profitable under current market conditions: even under the most optimistic assumptions for the cost and revenue parameters, power-to-gas plants need to run for many hours during the year at very low prices (i.e. the long-term willingness to pay for electricity is very low) that do not currently exist in Europe. In an optimistic future scenario regarding investment costs, efficiency and revenues of power-to-gas, however, the long-term willingness to pay for electricity is higher than the lowest recently observed day-ahead electricity prices. When prices remain at this low level, investments in power-to-gas can thus become profitable.

## 1. Introduction

As part of their policies to reduce the emissions of greenhouse gases, many governments want to replace fossil energy systems by systems strongly based on renewable energy [1]. This transition coincides with several economic and social challenges. In electricity systems it creates a particular challenge due to the fact that generation from the renewable sources wind and sun is intermittent because it is related to weather conditions, while the electricity system requires a permanent balance between inflow and outflow (the so-called energy balance). An increasing supply of intermittent generation, hence, requires more flexibility within the system. At the same time, conventional fossil fuel power plants – currently the main providers of flexibility in many electricity systems – will be less available in future systems dominated

by renewable energy. Such systems will therefore have a large demand for flexibility from other sources.

One option that could provide flexibility in a renewable energy dominated system is power-to-gas (PtG). In this technology, electricity is used to split water into hydrogen and oxygen using an electrolyser. PtG can offer three types of flexibility to the electricity system: flexibility with respect to time, location and end-use.

The time flexibility of PtG is that it is able to adapt the timing of using electricity and producing hydrogen. If a PtG plant is equipped with a facility to store the hydrogen, the timing of the production process can be fully adapted to the fluctuations of the electricity prices, while the storage ensures that the hydrogen can be delivered to the market at times the customers prefer this or when the prices of this gas are most beneficial.

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The location flexibility of PtG is that it enables alternative locations for electricity production by possibly reducing the energy transportation costs. Instead of transporting electricity produced by, for instance, offshore wind farms through an electricity grid, the electricity can be transformed into hydrogen close to the wind farm and transported directly to the consumers using ships or pipelines. Further conversion of the hydrogen into methane could allow usage of the already existing natural gas grid, which means that hardly additional transportation costs have to be made. Since high-voltage electricity grid lines are very capital intensive, this can lead to significant reductions in transportation costs of renewable energy, especially when it is generated at remote locations far from demand centres and distances are large.

The end-use flexibility of PtG is that it can be used to supply users other than electricity consumers with renewable energy without the need for these users to transform their own energy systems. Examples are the industrial and transportation sector. For this, the generated hydrogen can be used directly but could also be further converted into another substance such as methane, methanol or ammonia.

In this paper, we focus on the time flexibility of PtG. This flexibility may contribute to the need for extra flexibility in an electricity system with high shares of intermittent renewables. PtG can offer two types of time flexibility: it can serve as a real electricity storage technology where the produced hydrogen is reconverted back to electricity when required or as a demand side response technology where PtG becomes a flexible electricity consumer.

In the first time-flexibility option, PtG can be compared to other electricity storage technologies such as batteries, pumped hydro storage (PHS), flywheels or compressed air energy storage (CAES). PtG is able to store large amounts of electricity for a very long time, making it suitable for seasonal electricity storage. For this to be profitable, the spread between electricity prices in summer and winter needs to be sufficient to cover the investment. Although seasonal storage does not seem to be economically feasible in the near future, it could become very important in a fully renewable power system in the future. Heide et al. [2], for example, studied the storage needs in such a future power system based on 100% wind and solar power and concluded that the large need for storage can only be provided by a combination of PHS and PtG with underground hydrogen storage in salt caverns.

In the second time-flexibility option, PtG can be compared to other power consumers that can be flexible such as organised charging of a pool of electric vehicles or power-to-heat. Instead of using the hydrogen to generate electricity again, it is sold to the industrial or transportation sector. It is generally concluded that direct selling of hydrogen is economically much more beneficial than reversion back to electricity due to the high revenues for hydrogen that can be achieved compared to those of electricity generation (e.g. [3–6]). Demand side response technologies can profit from low electricity prices during times of high (renewable) energy supply and low demand and avoid buying electricity at very high prices during times of low supply and high demand. Most power consumers need a stable supply of electricity, which means that it is costly for them to adapt to changing electricity prices in the short term. A PtG plant, however, can be operated in a flexible way, although additional investments are needed in the form of hydrogen storage to buffer the fluctuating production of hydrogen, which make the plant more expensive. Another factor making flexible operation of PtG more costly is the fact that it results in a lower equipment amortization: the available capacity is not fully utilized and needs to be expanded to be able to produce the same volumes in a flexible way. The business case of flexible operation of a PtG plant, therefore, depends on a trade-off between the lower electricity prices on the one hand and higher investment costs on the other hand per unit of hydrogen produced. For flexible PtG operation to be profitable, there need to be a sufficient number of hours in which the electricity price is sufficiently low.

In this paper we investigate to what extent PtG is a feasible option for providing time flexibility to the power system as a demand side

response technology. Hereby we focus solely on the conversion of electricity into hydrogen (power-to-hydrogen). We analyse the market conditions (i.e. electricity prices) under which PtG is able to operate economically. This means that we analyse the maximum electricity price a PtG plant operator is willing to pay in case the investment in the installation (including storage facility) has already been made (short term) as well as when the investment still needs to be made (long term). Next, we explore the feasibility of these maximum prices under current and future electricity market conditions, taking into account the existence of other options for flexibility in the electricity system.

Operation of PtG plants in electricity markets has already been investigated by a large number of different studies (e.g. [5,7–9]). The contribution of our paper is that we develop and apply new economic metrics to assess the economic feasibility of PtG, which have not been used before in this field of research. Instead of calculating the hydrogen production costs, we perform a reverse analysis in which the price of hydrogen is fixed and the willingness to pay (WTP) for electricity is calculated. The WTP is then compared with the level and volatility of current European electricity prices in day-ahead and intraday markets to determine whether or not large-scale investments in the technology will be feasible. Our methodology allows for a thorough investigation of PtG plants in (future) electricity markets and puts the general thought that PtG plants can profit from low electricity prices in perspective. This approach enables us to explore systematically the economic potential of PtG in future electricity markets dominated by renewables.

The structure of the paper is as follows. In chapter 2 we describe the methods that are used. Chapter 3 presents the data that are used for the analysis: we describe the technology PtG and its current costs and revenues and we give an overview of the electricity system in four European countries (Germany, France, the Netherlands and Denmark) that differ significantly in their power system characteristics (including power generation portfolio, market structure, interconnection and electricity prices). Chapter 4 gives the results of the analysis and shows the maximum electricity prices a PtG plant operator is willing to pay and the feasibility of these prices for current as well as future market conditions. Chapter 5 finally discusses the results and concludes.

## 2. Method

Our methodology to assess the business case of PtG consists of two steps. First, we evaluate the costs and revenues of this technology and determine the maximum electricity price a PtG plant operator is able and, hence, willing to pay. In a second step, the feasibility of these maximum electricity prices is evaluated. The two-step procedure is first carried out for the current situation and afterwards for the future when the PtG technology is further developed and the electricity system contains higher shares of variable renewables.

### 2.1. Willingness to pay for electricity

To determine the willingness to pay (WTP) for electricity it is important to differentiate between the short-term and the long-term. In the short-term – when the plant has already been built and is operational – an operator only looks at the marginal costs and revenues to decide whether or not he will buy electricity during a specific hour to operate the plant. Besides electricity, water is the only feedstock of a PtG plant. The short-term WTP for electricity (in €/MWh) is therefore determined only by the costs for water (in €/kg H<sub>2</sub>), the revenue of the hydrogen (in €/kg H<sub>2</sub>) and the power consumption of the electrolyser (in MWh/kg H<sub>2</sub>), following Eq. (1):

$$\text{electricity WTP}_{\text{short-term}} = \frac{(\text{revenue H}_2 - \text{costs H}_2\text{O})}{\text{Power consumption electrolyser}} \quad (1)$$

The power consumption of the electrolyser depends on its efficiency, which is usually defined as a percentage using the higher heating value (HHV) of hydrogen. Eq. (2) shows how the power

consumption of the electrolyser (in MWh/kg H<sub>2</sub>) is determined using the efficiency, the HHV (which is 3.54 kWh/Nm<sup>3</sup>) and the density  $\rho$  of hydrogen (which is 0.0899 kg/Nm<sup>3</sup>).

$$\text{Power consumption electrolyser} = \frac{\text{HHV}}{\text{efficiency} \cdot 1000 \cdot \rho} \quad (2)$$

The number of operating hours in a year is determined by the short-term WTP: the plant will only operate when the marginal costs do not exceed the marginal revenues.

In the long-term, the WTP for electricity depends on all costs and revenues of the PtG plant, including the fixed costs, which consists of the CAPEX and yearly fixed OPEX. The burden of these costs is spread over the total volume of hydrogen that is produced during the lifetime of the PtG installation (for CAPEX) or during the year (for OPEX). The long-term WTP, therefore, depends on the yearly full load hours and the lifetime of the plant. Eq. (3) shows the formula that is used to calculate the long-term WTP for electricity, with all costs and revenues given in €/MW installed capacity while  $h$  refers to the number of hours per year the plant is in operation.

$$\text{electricity WTP}_{\text{long-term}} = \left[ \frac{\text{Yearly } H_2}{\text{revenues}} - \left( \frac{\text{Yearly } H_2O}{\text{costs}} + \frac{\text{Yearly OPEX}}{\text{OPEX}} + \frac{\text{Yearly CAPEX}}{\text{CAPEX}} \right) \right] / h \quad (3)$$

The yearly revenue of the sales of hydrogen and the yearly costs of water (both in €/MW installed capacity) can be calculated using their respective prices, the amount of hours the plant is in operation and the production/consumption per hour per installed MW electrolyser capacity. Yearly OPEX costs are usually defined as a percentage of CAPEX for different components of a plant. The investment costs must be spread over the  $n$  years of lifetime of the investment. Assuming a discount rate  $i$ , the annual capital costs of the investments can be calculated by using the capital recovery factor (CRF) [10]:

$$\text{CRF} = \frac{i(1+i)^n}{(1+i)^n - 1} \quad (4)$$

Besides investments done in the beginning of the project, there are also investments to be done later on, when parts of the plant need to be replaced. These costs must first be converted to the present value, before they can be spread over the total lifetime of the project. The present value factor (PV-factor) for the year  $n$  can be calculated as follows:

$$\text{PV}_n = (1+i)^{-n} \quad (5)$$

The yearly CAPEX is calculated using Eq. (6), in which CRF is the capital recovery factor as was defined in Eq. (4), CAPEX<sub>ini</sub> is the initial CAPEX at the start of the project and PV <sub>$n$</sub>  is the present value factor calculated for year  $n$  in which investment CAPEX <sub>$n$</sub>  took place.

$$\text{Yearly CAPEX} = \text{CRF} \cdot (\text{CAPEX}_{\text{ini}} + (\text{PV}_n \cdot \text{CAPEX}_n)) \quad (6)$$

Because the long-term WTP for electricity depends on the yearly full load hours of the plant, it is not a single number but a functional relationship that describes how the WTP depends on the number of operating hours of the PtG plant. The relationship can be expressed graphically and can be compared to an electricity price curve, which describes the average price of electricity during the cheapest  $x\%$  of hours in a year. The calculation of such an electricity price curve is illustrated in Fig. 1. The black line shows the electricity prices throughout a year, ranked from lowest to highest. This is in principal a load duration curve, albeit that here the hours are ranked from the lowest to the highest level. We use this reverse order because our analysis is directed at finding the WTP for electricity, which has to be compared with the likelihood of low prices in the electricity market. The red line is based on the black line and shows the average electricity price during the cheapest  $x\%$  of hours in the year. This means that, for example, the black line at hour 2190 shows the price at hour 2190 when the hours are ranked from lowest to highest price, and the red line

shows the average of this hour and all hours with a lower price, i.e. the hours 1 – 2190. The last point of the red curve (i.e. at hour 8760) thus gives the average electricity price over the whole year. In this paper we will continue with this average electricity price curve, whereby the average electricity price is placed on the x-axis and the share of hours on the y-axis. The reason for this is that in our analysis we depart from the average electricity price and then wonder how often that price should be realized in order to make the project break-even. The non-standard way of presenting also helps in distinguishing our curves from standard load-duration curves.

The graphical comparison between the long-term WTP curve and the average electricity price curve is illustrated in Fig. 2. Whether or not investment in a PtG plant is profitable depends on the position of the two curves: the investment is profitable if the long-term WTP curve is somewhere below the average electricity price curve. In Fig. 2, the left panel shows a situation where this is not the case: the price needs to be below 10 €/MWh for almost 100% of the time, while the actual price is never below 10 €/MWh. In the right panel of Fig. 2 a profitable business case is possible. The price needs to be, for instance, below 25 €/MWh for at least 70% of the time and the actual average electricity price is below this level for almost 90% of the time.

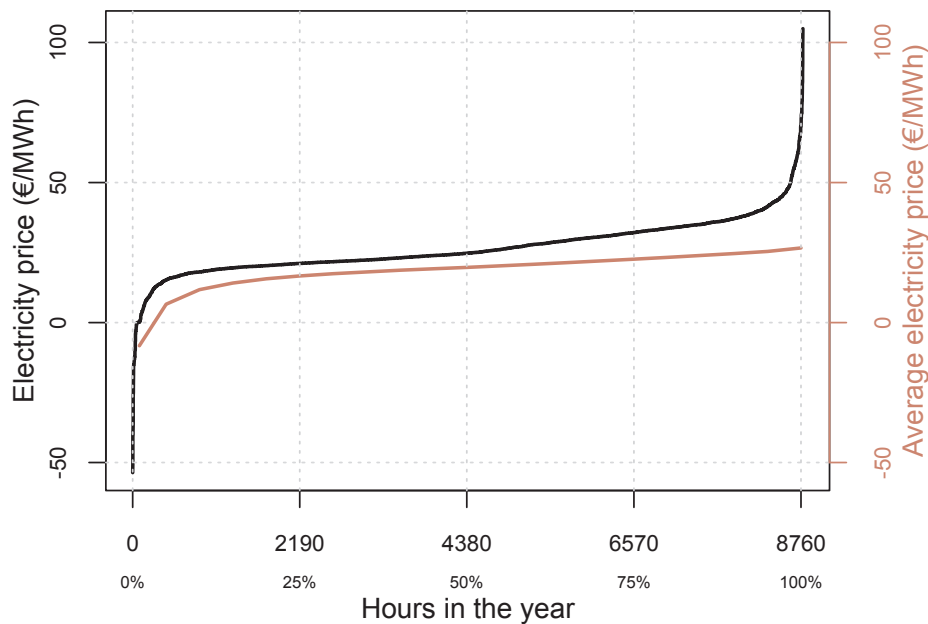
When calculating the short-term and long-term WTP for electricity, we first focus on current market conditions, estimating the current CAPEX and OPEX of the technology and considering current water costs and hydrogen revenues. Since the technology PtG is in an early development stage, there are no widely accepted values for most of the cost and revenue parameters of the technology. Different literature sources report different values, leading to different results in calculations. To explore the effect of the uncertainty in the cost and revenue parameters of PtG on the business case, we define a downside and upside boundary in addition to a base case. The boundaries represent the lower and upper literature estimates of the parameters, excluding very extreme values. After this analysis of the current business case of PtG, we assess the future potential of the technology by identifying the most important parameters and their potential future values.

## 2.2. Feasibility of the willingness to pay for electricity

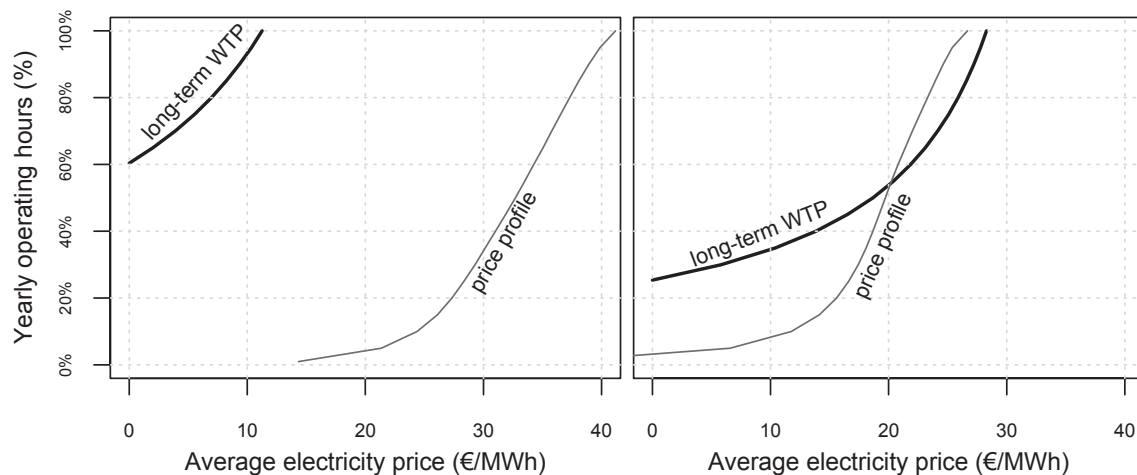
Because electricity markets are regional markets, the feasibility of PtG depends on the type of market it is operating in. In this paper, four European countries are chosen that vary significantly in their power generation portfolio, interconnection with their neighbours and market design. These three characteristics mainly determine the electricity price: both the average as well as its volatility. Different types of power plants have different costs and are different in the flexibility that they offer. Wind power and nuclear power have very low marginal generation costs but are both rather inflexible, while gas-fired power plants have relatively high generation costs, but are very flexible and capable of ramping up and down very fast. Hydropower is both relatively cheap and flexible, meaning that countries with large shares of hydropower (such as Norway) usually have rather low electricity prices with limited volatility. Interconnection to neighbouring countries can also lower the electricity price and reduce volatility as demand and supply can be averaged over a larger area. Countries without their own hydropower plants may get access to such plants abroad, which can be very beneficial for the integration of variable renewables (e.g. [11]). Finally, the market design can also have an influence on the electricity prices. Market design parameters that vary among countries are for example the trading times (closure of different markets) and types of products (hourly, quarter-hourly).

To evaluate the operation of PtG plants under current market conditions, recent (2013–2017) electricity prices in day-ahead and intraday markets in four countries are studied.<sup>1</sup> For the evaluation, not only

<sup>1</sup> Participation of a PtG plant in the real time balancing market will not be



**Fig. 1.** Example of the calculation of an average electricity price curve that is required for assessing the feasibility of the long-term WTP of a PtG plant. The black line represents the electricity prices during a year, ranked from low to high. The red line represents the average of all electricity prices up to the electricity price at that point. The latter curve is used in our analysis.



**Fig. 2.** Example of the functional relationship of the long-term WTP for electricity compared to an average electricity price curve to see whether a PtG plant can make a long-term profit (right panel) or not (left panel).

average prices are relevant but especially also the electricity price patterns (i.e. the volatility). A key question is whether or not some countries and markets are more beneficial for PtG plants than others. To assess the future business case of PtG, developments in the electricity prices are discussed based on the recent prices presented in this paper as well as on literature.

### 3. Data

#### 3.1. Data on costs and revenues of PtG

This section briefly discusses all PtG cost and revenue parameters. Current values for the base case and upside and downside boundaries of

(footnote continued)

taken into account in this paper, as this would require a very different analysis. The reader is referred to other literature sources that discuss PtG participation in the balancing market (e.g. [3–5,7,12–14]). It can be concluded that literature sources are not conclusive about what is the best operating strategy for PtG plants on the balancing market and whether or not this is more profitable than participation in the DA market.

the parameters are summarized in Table 1.

The core of every PtG plant is the electrolyser. In an electrolyser, electricity is used to split water into hydrogen and oxygen. Two main electrolyser techniques are currently available for the market: alkaline electrolysis and proton exchange membrane (PEM) electrolysis. In this paper we only consider alkaline electrolysers to assess the current business case of PtG. These electrolysers are more mature and cheaper than PEM electrolysers [15–17] although it must be noted that the difference between the two technologies is getting smaller and investment costs of PEM electrolysers are now approaching those of alkaline electrolysers [18].

Investment costs for alkaline electrolyser systems (including not only the electrolyser stack but also all other equipment such as water treatment, power conversion and structure housing) are currently reported to be in the range of 1000–1500 €/kW<sub>el</sub> [15–17,19,20]. It is generally assumed that replacement of the electrolyser stack is needed after ~10 years [15,21–23] and we assume costs for this are 30% of the CAPEX of the electrolyser system, following [20].

To be able to operate flexibly and buffer a fluctuating electricity supply or hydrogen demand, a PtG plant needs a hydrogen storage facility. We assume the hydrogen is stored in high-pressure steel tanks as



**Table 1**

Base case assumptions and upper and lower boundaries for all current cost parameters (except for electricity) and the hydrogen revenue of a PtG plant.

	Base case	Downside boundary	Upside boundary	Reference(s)
CAPEX electrolyser system (€/kW <sub>el</sub> )	1250	1500	1000	[15–17,19,20]
CAPEX electrolyser stack (%CAPEX system)	30%	30%	30%	[20]
Lifetime electrolyser stack (years)	10	10	10	[15,21–23]
Efficiency electrolyser system (% HHV)	67%	59%	72%	[12,44–46]
O&M costs electrolyser (% of CAPEX)	4%	5%	2%	[15,20,25,33,37]
Hydrogen storage size (# of hours)	12	12	12	–
CAPEX H <sub>2</sub> storage (€/Nm <sup>3</sup> H <sub>2</sub> )	60	100	20	[19,25–35]
O&M costs H <sub>2</sub> storage (% of CAPEX)	1.5%	2.5%	0.5%	[26,28,33,35,37–39]
Installation & design costs (% of CAPEX)	30%	40%	20%	[38]
Discount rate <i>i</i> (%)	6%	6%	6%	–
Plant lifetime <i>n</i> (years)	20	20	20	–
Water price (€/kg)	0.00069	0.00069	0.00069	[43]
Water needed (kg water/kg H <sub>2</sub> )	17.9	17.9	17.9	[22,23,44]
Hydrogen revenue (€/kg)	1.25	1.00	1.50	[14,47–49]

this is currently the most widely used technique for hydrogen storage in PtG plants [24]. The required size of the storage tank depends on the configuration of the plant (electrolyser operation) and utilization of the hydrogen (supply to the customers) and is hard to generalise. We assume a rather arbitrary chosen storage size of 12 h of hydrogen output from the electrolyser when operated at full load. Investment costs for hydrogen storage in high-pressure steel tanks vary widely in literature. Prices tend to fall in the range of 20–100 €/Nm<sup>3</sup> [19,25–35], but extremes are reported up to 195 €/Nm<sup>3</sup> [36] or even 490 €/Nm<sup>3</sup> [8]. The lifetime of hydrogen storage tanks is assumed to be 20–30 years [25,26,33,35,37–39]. Additional investment costs for a compressor are disregarded in this paper. Costs for this are hard to determine since the design of a compressor is very dependent on the configuration of the plant (output pressure of the electrolyser, storage pressure, flow) and estimates for the CAPEX of hydrogen compressors vary widely in literature (in the range of 144–18,500 €/kW [20,27,31,33,36,37,40,41]). A compressor might indeed not be required when a high-pressure electrolyser is used [24,33] but one has to keep in mind that costs for hydrogen storage might be higher than what is assumed in this paper.

To realise the building of any plant, additional costs have to be made for installation, planning, design and preparation. We assume that these costs are an additional 30% of the CAPEX of the plant components, roughly following [38,42].

Besides electricity, water is the only feedstock of a PtG plant. Water is relatively cheap in Europe and its costs do not add much to the total costs of operating an electrolyser. We assume a fixed price of 0.69 €/m<sup>3</sup> (0.00069 €/kg) based on the tariffs in 2017 of the company Vitens that is delivering water to a large part of the Netherlands [43]. We assume the need for water to be 200% of the stoichiometric need, following specifications of electrolyser manufacturers [22,23,44].

A wide range of hydrogen revenues is considered in different literature sources that discuss the business case of PtG. In this paper, the hydrogen revenue is set equal to the hydrogen production costs from steam methane reforming (SMR) – currently the most important hydrogen production technology – just as is done in [14]. Hydrogen production costs from SMR are estimated at ~1.25 €/kg [14,47–49]. Higher revenues for the PtG hydrogen might be possible when a bonus is considered for the green character of the produced hydrogen – as opposed to the conventional (grey) hydrogen produced with SMR – assuming that renewable electricity was used. Some literature sources (e.g. [5]) state that very high revenues for hydrogen can be achieved in the transportation sector, when the fuel price of hydrogen for fuel cell electric vehicles is set equal to the fuel price of petrol per driven km. In this case, the price can be as high as 9.5 €/kg, a value that is reported by the German clean energy partnership for hydrogen at refuelling stations [50]. Taking this price directly as the revenue of a PtG plant is, however, not realistic as costs for transporting and distributing the hydrogen to refuelling stations should be distracted first, as well as

costs for operating the refuelling station and storage and dispersion on site. Furthermore, there is currently almost no market for hydrogen in the transportation sector since so far there are hardly any fuel cell electric vehicles on the road.

Besides hydrogen, a PtG plant also produces oxygen that can be marketed to generate extra revenues. So far, however, all existing PtG plants vent the oxygen to the air and the potential of selling it is considered to be low [51]. Nevertheless, there might be some exceptions, mainly in cases where the produced oxygen can be used on site in, for example, a wastewater treatment plant for activation of sludge or for gasification of biomass [52,53]. Low-temperature heat from the electrolyser is another possible side product of a PtG plant that can bring additional revenues, but these will be very site-specific and cannot be generalized. In our calculations of the WTP, we do not take into account any revenues from oxygen or heat.

### 3.2. Data on electricity markets

In order to analyse the feasibility of PtG in different types of electricity markets, we analyse four European countries (Germany, France, the Netherlands and Denmark) that differ significantly in their electricity system characteristics and for which recent (2013–2017) electricity prices are available. Here we describe the structure of the electricity markets, power generation portfolios, cross-border interconnections and electricity prices in these countries.

#### 3.2.1. Structure of the electricity markets

It is important to realize that electricity markets consist of a number of consecutive markets, from long-term forward to real-time markets. For the analysis of the WTP for electricity of PtG plants we therefore need to go into the functioning of these various markets. Power producers and consumers schedule their production and consumption ahead, from years before actual delivery up till close to real time. Forward markets typically last until one day before delivery when the day-ahead (DA) market starts, followed by the intraday (ID) market. After closure of the ID market the transmission grid operator (TSO) takes over the responsibility for balancing the electricity grid in real time by activating reserve capacities. The provision of reserve capacities is arranged on forehand in balancing markets.

In Germany, France and the Netherlands, there is one market zone for the whole country. In Denmark, the country is split into two market zones: DK1 (west) and DK2 (east). In France, the Netherlands and Denmark there is one TSO that is operating the grid (RTE, TenneT NL and Energinet DK, respectively) whereas Germany has four TSOs that all manage their own area (TenneT, Amprion, 50Hertz and TransnetBW).

The DA market is generally considered to be the most important electricity market with the highest trading volumes and number of

participants. The price from this market is therefore usually referred to as ‘the’ electricity price. For every hour, market participants determine how much electricity they are willing to buy or sell and at what price. On exchanges, computer algorithms determine the market price for every hour, based on all the bids. For Germany, the Netherlands and France, electricity is traded on the platform of EPEX SPOT. For Denmark, this is done at Nord Pool. In addition to trade at these platforms, there is also Over-the-Counter trading, where brokers set the price. Here, we only look at the DA auction trading results.

The ID market starts after closure of the DA market and continues until 60, 30, 20 or even 5 min before delivery, depending on the country and market. Since the market operates closer to real time than the DA market it offers market participants the possibility to adjust their market position using information that became available after closure of the DA market such as renewed weather forecasts or new information on plant outages. Due to this, the ID market can play a key role in the integration of variable intermittent renewables in the power mix.

In general, ID markets are hourly continuous markets where prices are set bilaterally on a first-come, first-serve principle. As a consequence, there is no single market-clearing price for every hour as is the case in the DA market. Instead, the hourly market price is usually characterised by a lowest bid, highest bid, latest bid, weighted average bid and total trading volume [54,55].

Table 2 shows the average of the DA and ID electricity prices in Germany, France and Denmark (DK1) in 2017. On average, ID prices are slightly higher than DA prices, but the differences are small in all three countries. For the Netherlands, ID data were not available.

Fig. 3 shows the hourly ID and DA electricity prices in Germany, France and Denmark (DK1) plotted against each other for the year 2017. The figure shows that ID and DA electricity prices are very similar during most hours in the three countries. All countries showed negative electricity prices in 2017 in both the DA and ID market, but in France and Denmark this was very limited compared to Germany. Germany shows the most extreme price differences between the DA and ID market for both very low (negative) and very high prices. France also shows some extreme differences between the DA and ID market prices for high prices while Denmark hardly shows any extreme differences.

Because there are no significant differences between the hourly DA and ID electricity prices – apart from some extremes – the DA prices will be used further onwards in this paper. This is also justified by the fact that most of the electricity is traded in this market.

The German ID market is more extensive than the ID markets in the other countries. In the continuous market, quarter-hourly products are offered in addition to hourly products (since December 2011). These allow better approximation of real demand and supply and thereby facilitate the integration of variable renewables. They also align with the imbalance settlement period (ISP): a time slot within which market participants are supposed to maintain their energy balance. Next to the continuous market, the German ID market also has an auction – similar to the auction in the DA market – for quarter-hourly products that takes place at 15:00 o'clock on the day before delivery [54,57]. This auction was introduced in December 2014 and generates a reference price for the 15-minute time slots in the continuous ID market that follows [58]. Since the introduction of the auction, intraday trading volumes have significantly increased [59,60] and it was found that it increased market liquidity and led to reduced price volatility [59]. Fig. 4 shows

the DA and ID electricity prices for Germany in 2017 averaged per (quarter) hour of the day.

The hourly data presented in Fig. 4 show a clear daily pattern – which is similar in all four studied countries – with a peak in the morning around 8:00 o'clock and one in the early evening around 19:00 o'clock. The hourly average DA and ID prices are almost the same. The quarter-hourly data show a typical zigzag pattern, which is caused by the production design of fossil power plants and the power-intensive industry and during the day also by solar power producers as is explained in [61].

### 3.2.2. Power generation portfolios

As can be seen in Fig. 5, the power generation portfolios vary strongly between Germany, France, the Netherlands and Denmark. For Germany, coal refers to both hard coal (17%) and lignite (23%). The other countries do not use lignite. Nuclear power has a large part in electricity generation in France and is also still an important electricity source in Germany. All four countries produce electricity from the variable renewable energy sources (VRES) wind and sun, whereby wind power has a larger share than solar power in all four countries. Most countries also generate a significant share of the electricity with other renewables. Biomass generated 8% and 12% of all electricity in Germany and Denmark respectively. Hydropower has a significant share in France where it generated 12% of all electricity in 2016.

Fig. 5 does not distinguish between the two Danish zones. In 2016, DK1 (west) produced much more wind power than DK2 (east), both in absolute (9.4 vs. 2.4 TWh) as well as in relative terms (49% vs. 30%) [55].

### 3.2.3. Interconnection with other countries

Fig. 6 gives an overview of the interconnections of Germany, France, the Netherlands and Denmark with their neighbours, including onshore and (planned) offshore connections. The transmission capacity is usually determined by congestion in the surrounding grids and therefore varies over time and can also be different for the two directions [68,69]. Cross-border connections are not always used for transporting electricity from one country to another but can also be used without really importing or exporting it. Electricity generated in the north of Germany, for example, can be transported to southern Germany through the Netherlands [70]. Because of these so-called loop (uncontrolled) flows, network operators do not allocate the full technical capacity to commercial transactions.

Fig. 6 is summarised in Table 3 that also includes the total power generation in the year 2016. To give some indication of relative cross-border capacities of the different countries, the table also gives the export capacity divided by the total power generation. This makes clear that Denmark (both DK1 and DK2) has a huge cross-border capacity compared to the other countries.

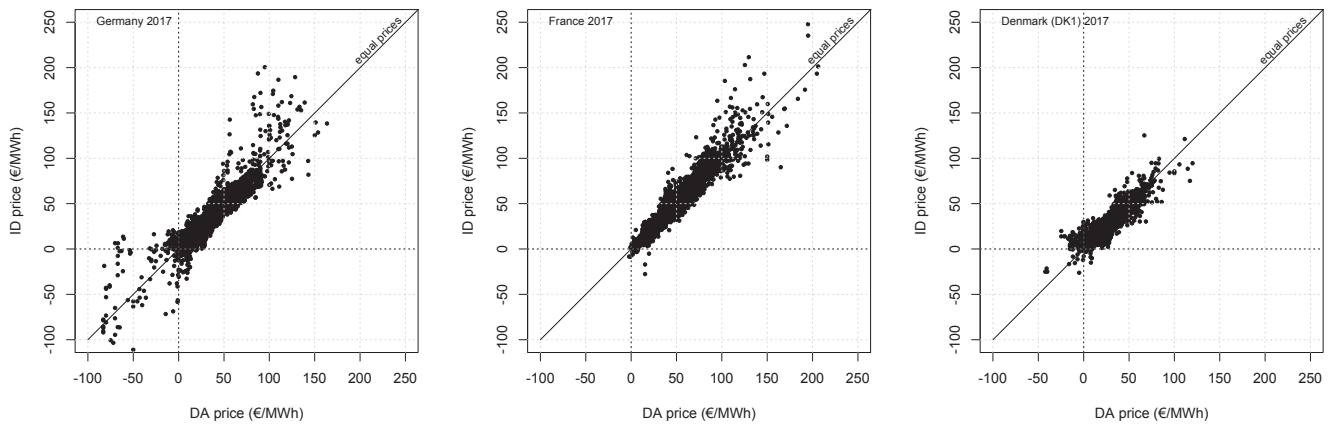
International integration of electricity markets is still a priority on the agenda of many European countries. All four countries are planning to increase their physical cross-border capacity but planning and construction of interconnectors is complex and takes a long time [78–80]. Besides expansion of the physical grid, countries also try to improve the utilisation of the grid. One option which has been applied to realise this is flow-based market coupling: a methodology in which the available capacity is optimized for trading [81,82]. International integration of electricity markets affects both the supply and demand of flexibility. An interconnector can increase the supply of flexible sources to a country and is thereby in fact a competitor for a PtG plant. In general one can say that increasing integration of markets results in less volatile prices, which may complicate the business case of PtG.

### 3.2.4. Recent (2013–2017) electricity prices

Fig. 7 shows the average DA electricity prices in Germany, France and Denmark (both DK1 and DK2) for the years 2013–2017 and in the Netherlands for the years 2013–2016. Average electricity prices were

**Table 2**  
Average DA and ID electricity prices in 2017 in €/MWh.  
Sources: [54–56].

	Germany	France	Denmark DK1
Day-ahead	34.20	44.97	30.08
Intraday	34.27	45.46	30.15



**Fig. 3.** ID and DA electricity prices in 2017 plotted against each other for Germany, France and Denmark (DK1). Sources: [54–56].

lowest in Denmark in almost all years, with DK1 being even lower than DK2. Although the price was decreasing throughout the years, 2017 shows higher prices than 2015 and 2016 in all countries.

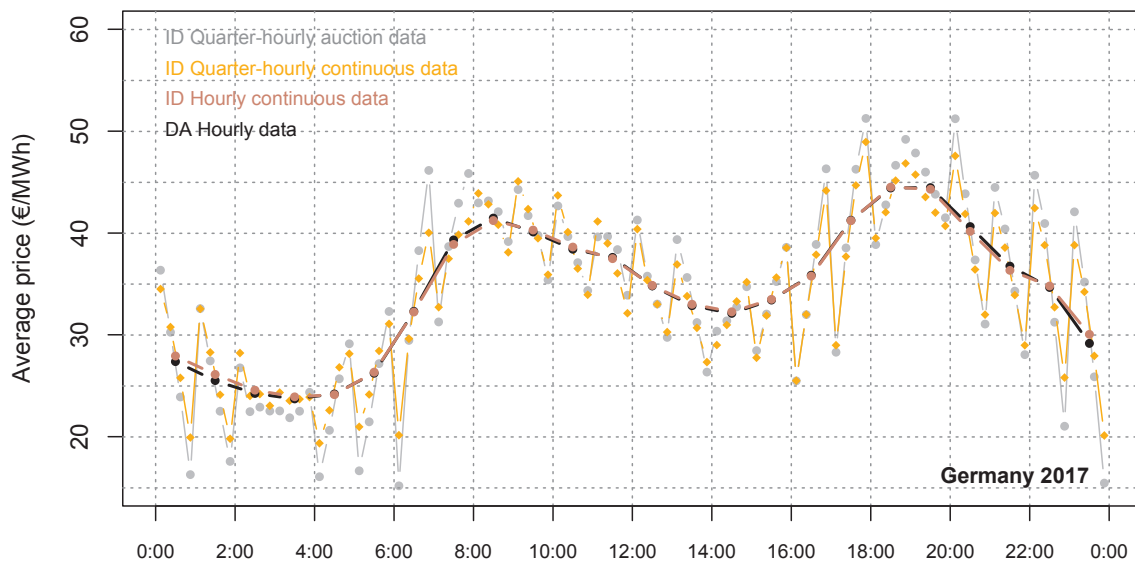
Although the average electricity price is a relevant metric for the feasibility of PtG – the lower the average price, the better it is for the business case of PtG – the electricity price pattern (i.e. the volatility) is even more valuable. Fig. 8 shows the average electricity price curves for the years 2013–2017 in the different countries, whereby the share of hours in a year is plotted against the average electricity price during that share of the year, similar to what was shown and explained in Fig. 1. The curves can be used to determine the average electricity price for a PtG plant when it operates only during the cheapest  $x$ -% hours in a year. For Denmark, we will only show DK1 prices further onwards in this paper, since this zone has lower prices and higher power production volumes compared to DK2.

The average electricity price curves vary strongly among the countries, and not only because of a difference in the overall average price (Fig. 8). The German average electricity price curves for 2014 and 2017, for example, are very similar in the middle of the curve, but differ for the lowest and highest prices: compared to 2014, 2017 shows more hours with very low prices and the sharp change of direction at  $\sim 95\%$  of full load hours indicates there were also more hours with high prices.

The lowest electricity prices in the last five years in the four studied

countries were observed in Denmark in 2015. In this year, there was a lot of wind power (51% of total power generation) and much less power production from coal (23%) than in other years [64,65]. This average electricity price curve can serve as a benchmark for the most favourable current market conditions. Other low average electricity price curves are DK1 2016 and Germany 2015 and 2016. The year 2013 showed the highest prices in Denmark, but represent a somewhat average pattern for all the studied countries and years. This curve can serve as a benchmark for average current market conditions. The Dutch curve of 2013 represents the highest electricity prices that were recently observed and can serve as a benchmark for the most unfavourable current market conditions.

Fig. 9 confirms that there are no significant differences between the hourly electricity prices in the DA and ID markets in Germany in 2017 (black and red curves). The quarter-hourly products (orange and grey curves), however, show a higher share of low electricity prices, even though the overall average price in 2017 is almost equal to the hourly DA and ID prices (this can be inferred from the figure as at 100% of the hours, all curves show roughly the same number). Although these lower prices are in principle beneficial for PtG plants, it would require more on-off switches for the electrolyser, since the minimum operating time becomes 15 instead of 60 min when participating in this quarter-hourly ID market. The greater unpredictability of the intraday prices worsens



**Fig. 4.** DA and ID prices averaged per (quarter) hour for Germany in 2017. For the ID data the average prices per (quarter) hour are taken. Sources: [54,56].



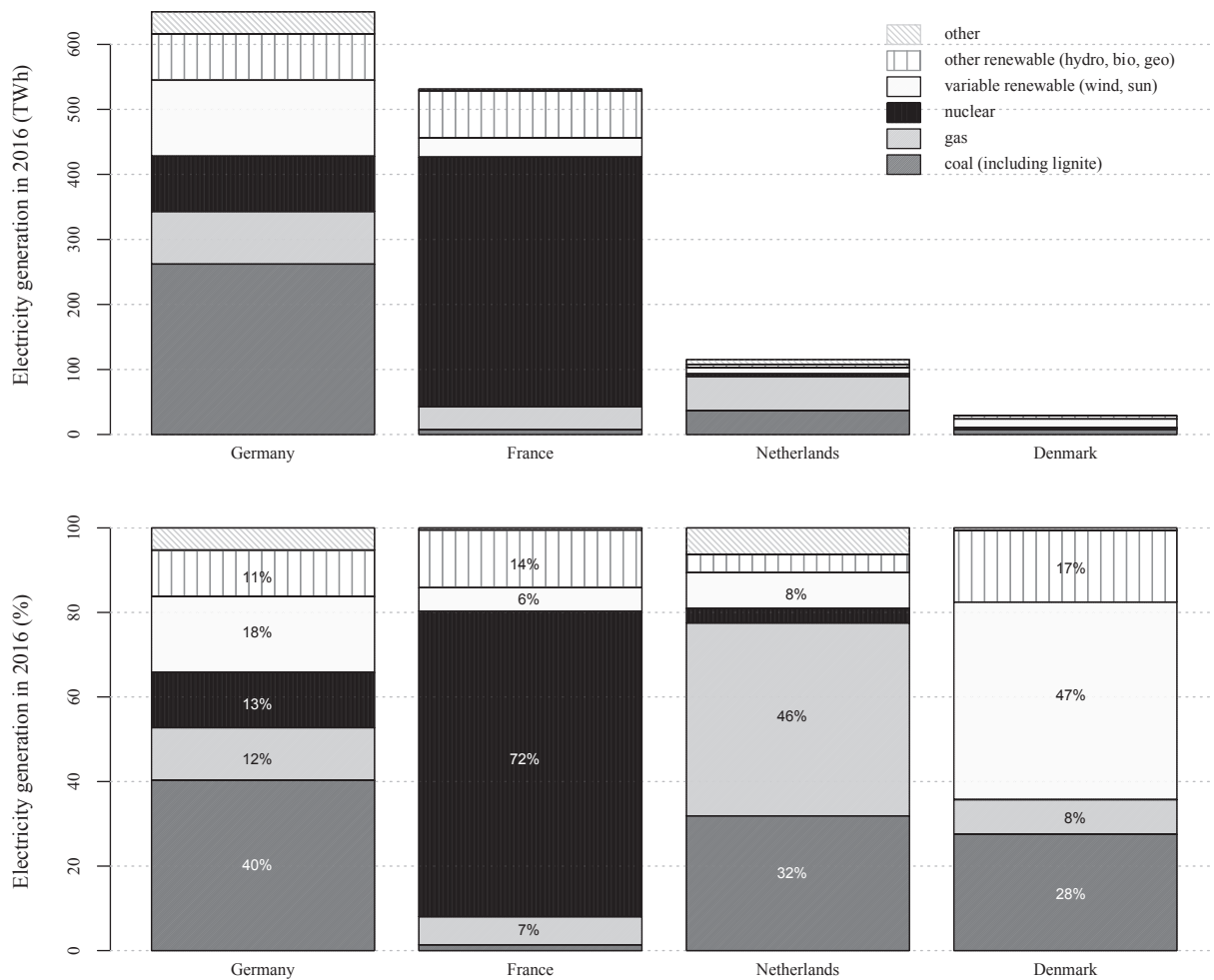


Fig. 5. Power generation by power source in the four countries in 2016. The upper graph shows the power generation in TWh in each country, whereas the lower graph shows the electricity generation per source in terms of percentage of the total electricity generation.

Sources: [62–67].

the problem of switching the electrolyzers on and off.

It is important to note that costs for electricity are not limited to the DA electricity price for most power consumers. There are additional costs in the form of fees and taxes. In Germany, for example, almost all power consumers have to pay the EEG surcharge,<sup>2</sup> which is a charge consumers have to pay for stimulating renewable energy in Germany. Since it was introduced, the EEG surcharge is increasing every year. Nowadays (since 2013) it is higher than the average DA market price and reached 68.80 €/MWh in 2017. For further evaluation of the PtG business case, we only take into account the DA electricity prices, but one needs to keep in mind that costs can be higher in reality.

## 4. Results

### 4.1. PtG operation under current market conditions

Table 4 shows the short-term WTP for electricity in the base case as well as for the downside and upside boundaries that were defined in Table 1. The higher the WTP for electricity, the more hours a plant will be able to run, as during more hours in a year the actual electricity price will be below the WTP. To put the values for the short-term WTP in perspective, Table 4 also gives the share of the year that the electricity price was below the reported WTP in Denmark in the years 2013 and

2015: the benchmarks for average and most favourable current market conditions respectively. As can be seen in the table, even under the most favourable assumptions for the cost and revenue parameters and the most favourable electricity market conditions, the PtG plant would not be able to run more than three quarters of the year.

Fig. 10 shows the long-term WTP for electricity, which is the maximum price a PtG plant operator is able to pay during a minimum number of hours. The WTP is presented for the base case and the upside and downside boundaries. To illustrate the feasibility of the prices, the curve with the most favourable average electricity prices that were recently observed (DK1 in 2015) is added to the graph.

Fig. 10 illustrates that PtG is currently far from a profitable business case. In the base case, the plant is operating break-even when the average electricity price is –4.90 €/MWh and the plant operates for 8760 h of the year. Even under the upside boundary assumptions, the PtG plant needs to run for many hours during the year at very low prices that do not currently exist in Europe.

### 4.2. PtG operation under future market conditions

Although PtG appears to be unprofitable under current market conditions, this might change in the future. As was demonstrated in Fig. 10, a PtG plant will likely never be able to operate economically without serious changes in the basic cost and revenue parameters. In this section, we first show the effects of potential changes in these parameters on the short-term and long-term WTP for electricity. Next,

<sup>2</sup> There are some exemptions for energy-intensive companies [83].



**Fig. 6.** Interconnections of the four countries with their neighbours including capacities. For continental connections the Net Transfer Capacities (NTC) are reported, which are generally two values that represent capacities to and from the countries respectively. The lines do not represent real geographical locations and one (continental) line can represent multiple connections in reality. For subsea interconnectors, reported capacities are the maximum capacities of the cables. Sources: [71–76].

**Table 3**

Export and import capacity of the four countries related to the total power generation in 2016 based on Figs. 5 and 6.

Sources: [71–77].

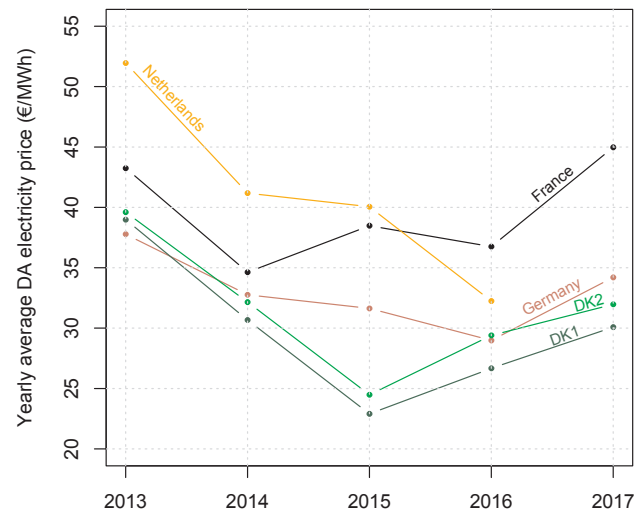
	Germany	France	Netherlands	DK1	DK2
Power generation 2016 (TWh)	650	531	115	19	8
Power consumption 2016 (TWh)	515	425	103	NA	NA
Connected to # countries	10	6	4	4	3
Total EXPORT capacity (MW)	15,880	15,175	7100	4540	3100
Total IMPORT capacity (MW)	17,300	10,095	7950	3990	3100
Export capacity/average hourly demand (%)	27	31	60	204 <sup>a</sup>	340 <sup>a</sup>

<sup>a</sup> For DK1 and DK2 export capacity is related to average generation instead of demand.

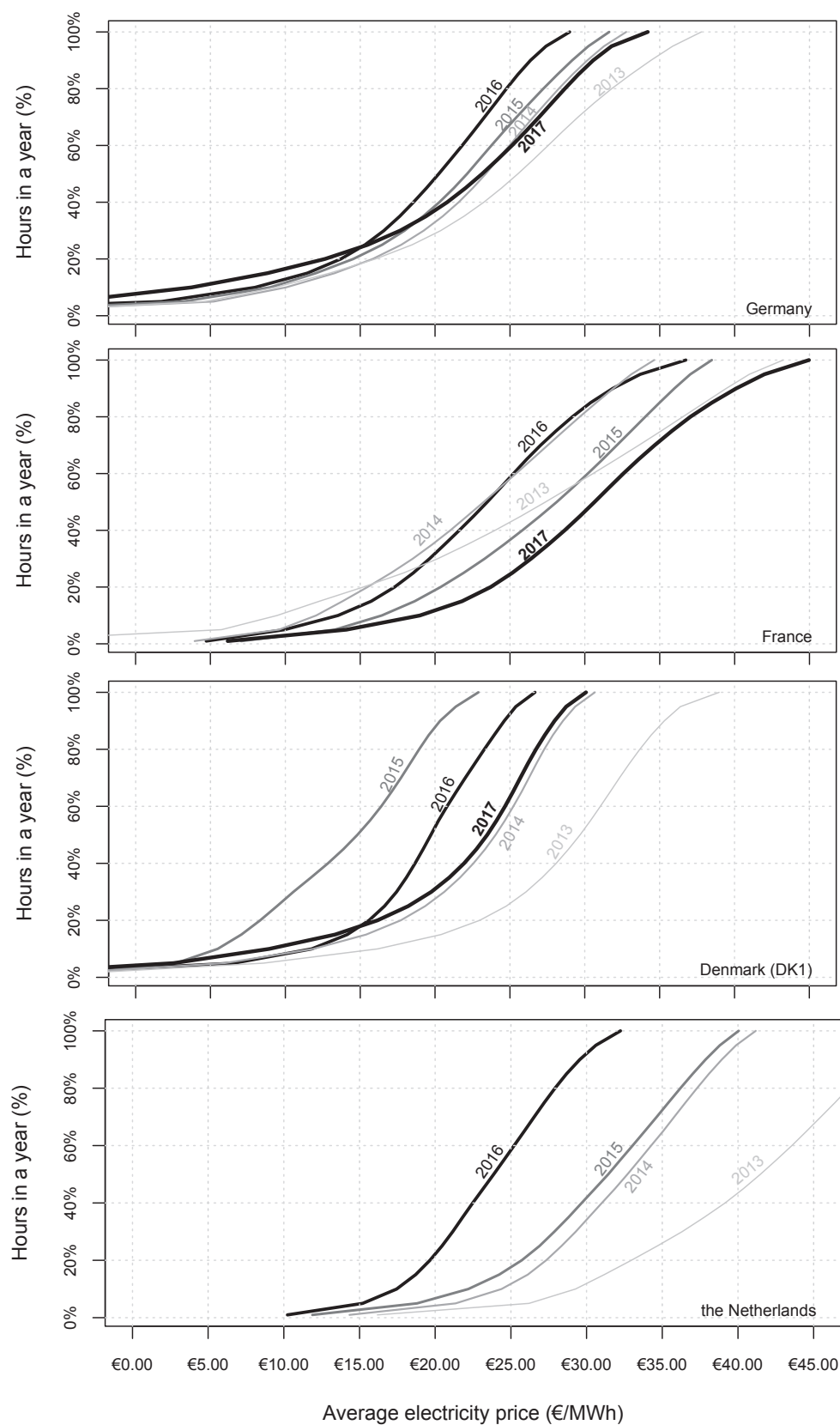
we assess how electricity prices might develop in the future under high shares of variable renewables in the power generation mix.

#### 4.2.1. Future developments of electrolyzers and the hydrogen market

Since electrolyzers are still fully in development, the CAPEX of both alkaline and PEM electrolyzers is expected to decrease significantly, with both technologies reaching investment costs of 500–600 €/kW<sub>el</sub>,



**Fig. 7.** Average day-ahead electricity prices in France, Germany, the Netherlands and Denmark (DK1 and DK2) in the years 2013–2017. For the Netherlands, data for 2017 are not available. Sources: [55,56].



**Fig. 8.** Average electricity price patterns in Germany, France, Denmark (DK1) and the Netherlands for the years 2013–2017 (for the Netherlands 2013–2016). The figure shows the average electricity prices during the x-% cheapest hours in the year in a certain country.  
Sources: [55,56].

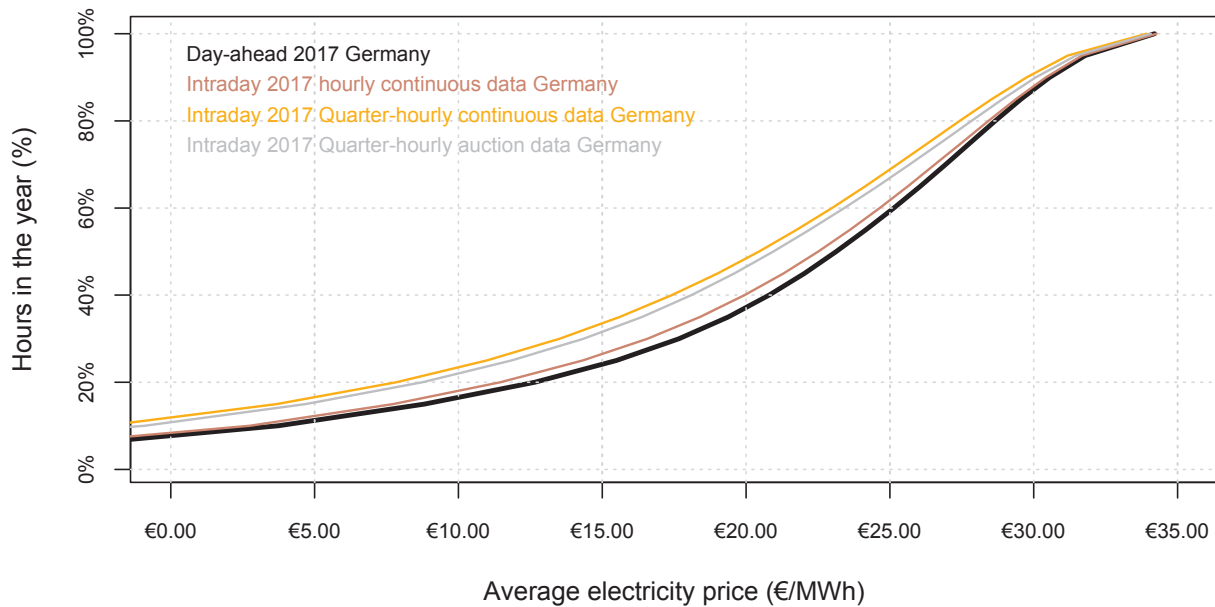


Fig. 9. Average electricity price curves of Germany in 2017 for the DA and three types of the ID market.

Sources: [54,56].

Table 4

Short-term WTP for electricity and the share of the years 2013 and 2015 the electricity price was equal to or below these prices in Denmark (DK1).

	Base case	Downside boundary	Upside boundary
Short-term WTP for electricity (€/MWh)	21.06	14.80	27.20
Share of DK1 2013 below this price (%)	6.0%	4.0%	9.9%
Share of DK1 2015 below this price (%)	38.3%	24.5%	74.4%

influences the PtG business case. In the evaluation of the technology under current market conditions, the hydrogen revenue was set equal to the production costs of hydrogen using the conventional method of SMR, as this is the competitive benchmark. In the future, these costs are likely to increase due to higher feedstock costs of the methane on the one hand and higher CO<sub>2</sub> penalties on the other hand. In [14], costs are estimated to increase from the current (2014) 1.23 €/kg to 1.54 and 1.84 €/kg respectively for the years 2024 and 2034. In the future, hydrogen from PtG plants might also compete with hydrogen produced from SMR combined with carbon capture and storage (CCS), whereby the CO<sub>2</sub> that is released during the production process of hydrogen is

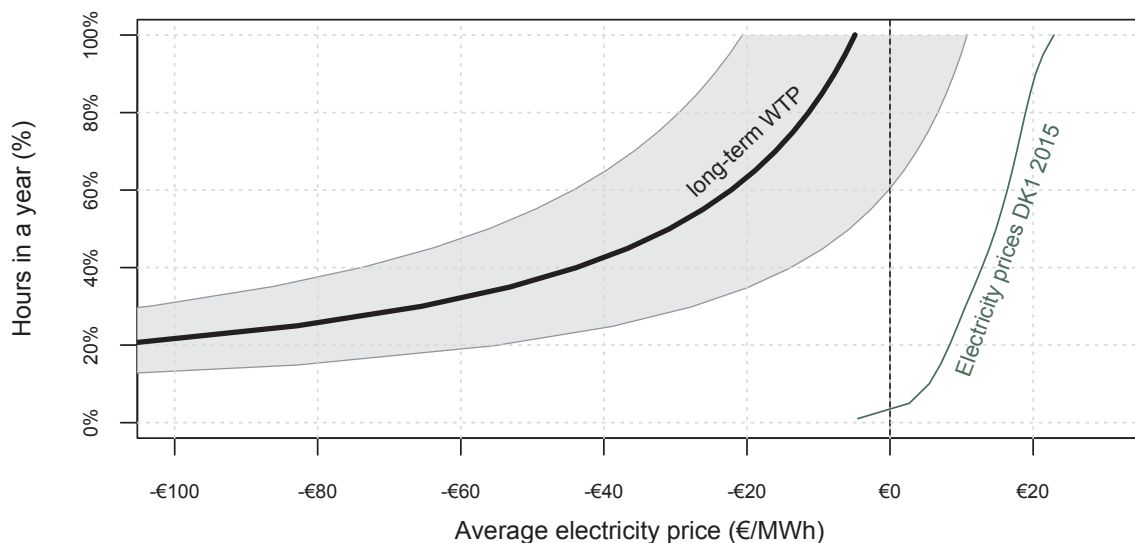


Fig. 10. Long-term WTP for electricity (the maximum price a PtG plant operator is able to pay during a minimum amount of hours) for the base case (fat line) and the upside and downside boundaries (indicated by the grey area). To illustrate the feasibility of the prices, the average electricity price curve from Denmark (DK1) in 2015 is added to the graph.

which is half of today's costs of alkaline electrolyzers [15–17,19,20]. An improvement in efficiency up to more than 75% (HHV) is also expected (e.g. [15,20]).

The revenue of selling the produced hydrogen also strongly

captured and stored underground instead of released to the atmosphere. Both technologies produce “green” hydrogen: hydrogen without a serious carbon footprint. Several literature sources report the increase in hydrogen production costs for SMR + CCS compared to general SMR.

**Table 5**

Future effects: changes relative to the base case and the short-term WTP for electricity under these cost and revenue assumptions. All other constants are as presented in Table 1.

	Base case	Higher efficiency	Lower investment costs	Higher H <sub>2</sub> selling price	All changes together
CAPEX electrolyser system (€/kW <sub>el</sub> )	1250	1250	500	1250	500
Efficiency electrolyser (% HHV)	67%	75%	67%	67%	75%
Hydrogen selling price (€/kg)	1.25	1.25	1.25	2.25	2.25
Short-term WTP for electricity (€/MWh)	21.06	23.57	21.06	38.07	42.62
Share of DK1 2013 below this price (%)	6.0%	7.1%	6.0%	56.5%	73.8%
Share of DK1 2015 below this price (%)	38.3%	49.4%	38.3%	91.1%	94.1%

In [49] the additional costs of CCS are identified to be 0.32 €/kg hydrogen, on top of the basic price of 1.19 €/kg, which is an addition of 27%. Also [84] reports a limited price increase of 15–28% for hydrogen when CCS is used in a SMR facility. In [48] it is estimated that costs for hydrogen increase by ~1 \$/kg from ~1.39 \$/kg to 2.5 \$/kg (~2.25 €/kg). In this paper, we take into account this last – for PtG most optimistic – price increase for hydrogen in a future scenario.

Table 5 shows the impact of three possible future effects (higher electrolyser efficiency, lower CAPEX and higher hydrogen revenues) on the short-term WTP for electricity compared to the base case that was presented earlier in Table 1. Just as was done in Table 4, the share of the year that the electricity price was equal to or below the calculated short-term WTP is given for Denmark (DK1) in 2013 and 2015. For lower investment costs, the short-term WTP does not change, since the investment costs do not influence the marginal costs and revenues of the plant. As can be seen in the table, the short-term WTP for electricity significantly increases when the hydrogen price is higher. As a consequence, the amount of operating hours under average and optimistic market conditions also significantly increases.

Fig. 11 shows the impact of the three future effects on the long-term WTP for electricity. The figure shows that a combination of lower electrolyser investment costs and higher hydrogen revenues is crucial to come to a profitable PtG business case. Increased electrolyser efficiency has only a minor effect. The combination of the three effects leads to a profitable business case under the most favourable current market conditions as represented by the lowest average electricity price curves from Fig. 8 (German and Danish prices in 2015 and 2016).

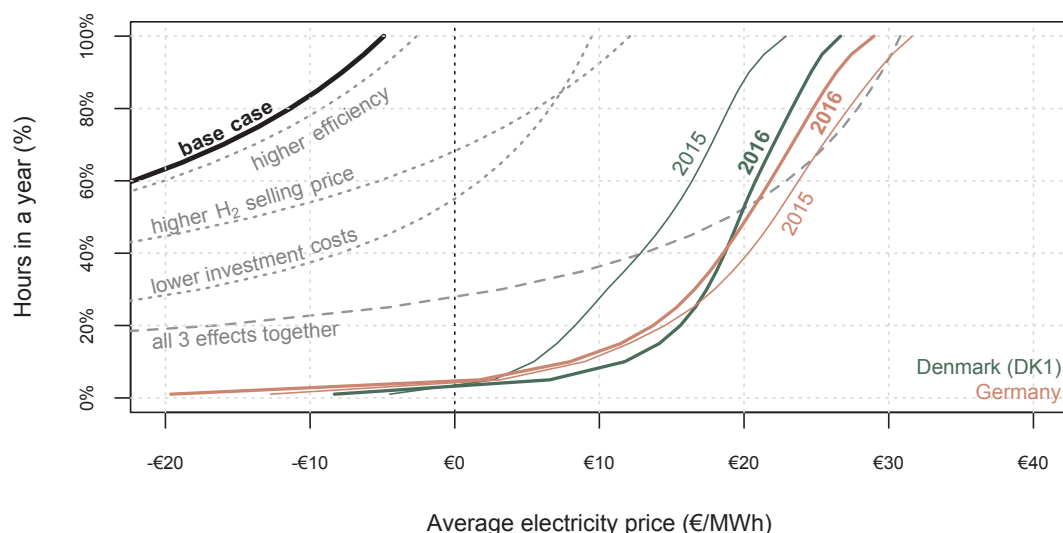
Once commissioned, whether a plant in a specific hour will run depends on the short-term WTP. In the case of a future with the three effects combined, the plant would thus operate for 94.1% of the time in Denmark in 2015 (see Table 5) under ideal circumstances.

#### 4.2.2. Future electricity prices

The previous section showed the effect of potential developments in the cost and revenue parameters of PtG plants on their short-term and long-term WTP for electricity. Lower costs and higher revenues would increase the yearly amount of operating hours and long-term profitability of PtG plants. Lower electricity prices would, however, have the same effect. Future electricity prices – both the level and volatility – are therefore also very important for the future business case of PtG plants. The development of future electricity prices depends on various factors including future power production portfolios, interconnection between countries, subsidies that are in place and sources of flexibility that are present.

All four countries analysed in this paper are planning to increase the share of renewable power generation and decrease the share of fossil fuels in the power mix. The Dutch government has recently announced to close all coal-fired power plants by 2030 at the latest [85]. More countries plan to phase out coal. At the UN Climate Change Conference in Bonn (COP23) in November 2017, an alliance of more than 20 countries announced phasing out of coal. These countries include the Netherlands, Denmark and France (but not Germany) [86]. After the nuclear disaster in Fukushima in March 2011, the German government decided to immediately close 8 older nuclear power plants and phase out the remaining 9 nuclear power plants completely by 2022 [87]. France planned to reduce the share of nuclear power to 50% of total power generation by 2025 [88], but recently announced that this target needs to be shifted to the 2030–2035 timeframe [89]. The closure of existing conventional power plants will have an upward effect on the power prices.

The further development of wind and solar power depends on the support mechanisms in place and whether or not subsidies are given for their development. Offshore wind farms in Europe were originally



**Fig. 11.** Changes of the long-term WTP for electricity for three different effects and their combination as presented in Table 5 with average electricity price curves in Denmark (DK1) and Germany in 2015 and 2016.



heavily subsidized but recently costs have dropped so fast that the first subsidy-free wind farms were tendered in Germany and the Netherlands in 2017. Without subsidies, wind farms rely completely on the electricity prices for their income. The building companies expect the electricity prices to rise in Europe due to the planned closure of nuclear and coal-fired power plants and as a consequence an increasing demand for other sources of electricity [90,91]. In addition, one may expect that the companies building new wind farms will determine the size of their investments such that the future electricity price will remain sufficiently high to recover their investment costs.

A study on the future power system and demand for flexibility in the Netherlands [6] showed amongst others possible future power price profiles in different scenarios. Wind and solar power have low marginal costs. As their share increases, so does the number of hours in which they set the price. Scenarios for the year 2050 indicate that the electricity price will be at its minimum of  $\sim 2$  €/MWh for as much as 2000–2500 h in the year. This might be just enough for investing in PtG plants: in our ‘all 3 effects together’ scenario (Fig. 11), the long-term WTP for electricity is 2 €/MWh when the plant is operated during 29% of the time, which is about 2550 h.

Brunner [92] discusses the impact of high shares of variable renewables on the electricity prices and distinguishes between short-term and long-term effects. If electricity becomes available at very low prices during many hours of the year, it can be expected that market participants will adapt to these prices. Flexible electricity consumers will start a competition for the cheap electricity, thereby increasing the electricity price up to their WTP [92]. In addition, one may also expect that the competitive process in the electricity market will make that the electricity price will be sufficiently high in the long term to give a proper return on investments in power plants, including renewables. This may also prevent that the electricity prices are low for a long period of time.

Green et al [93] investigated the long-term impact of large-scale hydrogen production from electrolysis on electricity prices and the power generation portfolio. The authors show that large-scale application of electrolyzers ultimately changes the optimal power generation portfolio, which will shift to higher shares of base-load capacity and lower shares of merit and peaking capacity. Although there could be a short-term opportunity for PtG plants to produce cheap hydrogen at times of excess wind, this will disappear in the long run when the power generation portfolio adapts to a new situation and the electricity prices stabilize again.

Inflexible power plants such as coal-fired and nuclear power plants face costs for shutting down and starting up again. At times that renewables cover the electricity demand while these “must run” power plants are also present, negative prices can occur, also because wind and solar power currently have a feed-in priority. The inflexible power plants prefer to sell the electricity at negative prices up till a certain price where it becomes cheaper to shut the plant down. For coal-fired power plants this fee is relatively small but nuclear power plants need authorisation from the state to restart and operators are willing to pay a significant fee (up to 120 €/MWh or more) to avoid a shutdown [94]. Without a feed-in priority, wind and solar power could be curtailed to prevent the costly shut down of base-load power plants. In a future power system with large shares of variable renewables, other power plants need to be more flexible.

Future power systems with predominantly (offshore) wind power have a larger potential for PtG than systems predominantly based on solar power due to the more irregular pattern of wind [95,96]. A worse agreement between electricity production and demand gives a larger potential for energy storage technologies such as PtG.

Summarized: the role of PtG in future power systems is hard to predict because it will depend on the overall layout of the power system that includes many uncertainties.

## 5. Discussion and conclusions

In this paper we analysed the business case of power-to-gas under current and future market conditions by evaluating the plant operator's willingness to pay for electricity in the short as well as in the long-term.

We find that a power-to-gas plant cannot operate economically under current market conditions – not even under the most optimistic assumptions regarding the technology and lowest recently observed electricity prices. A reduction of the investment costs of the power-to-gas technology ( $1250 \rightarrow 500$  €/kW<sub>el</sub>) combined with a higher electrolyser efficiency ( $67\% \rightarrow 75\%$ ) and higher hydrogen revenues ( $1.25 \rightarrow 2.25$  €/kg) can result into a profitable business case when the lowest recently observed electricity prices would hold in the future. It is important to remark that although the day-ahead electricity prices observed in Denmark and Germany in 2015 and 2016 were sufficiently low, this was not the case for all other power prices in the four countries of analysis (Germany, France, the Netherlands and Denmark) over the past five years. For large-scale investment in power-to-gas to come off the ground, electricity prices should become structurally lower, the hydrogen revenue must become even higher and / or the investment costs should even further decrease. One should, however, realize that the electricity price and hydrogen price are to some extent positively related to each other as a higher hydrogen price may result from a higher gas price, which also may raise the system marginal costs in the electricity market. As a result, a scenario of low electricity prices and high hydrogen prices may not be very likely.

Our results are in line with other studies that evaluated the business case of power-to-gas. It is generally concluded that intensive use of the plant is required to cover the high electrolyser investment costs (e.g. [9,13,97,98]). Studies only come to optimistic results with regard to flexible electrolyser operation when they either disregard investment costs (e.g. [99,100]) or are very optimistic about the availability of excess electricity at no costs during many hours of the year (e.g. [12,14]).

Whereas most studies take the electricity price as a given to calculate the hydrogen production costs, we did a reverse analysis in which the price of hydrogen is fixed and the willingness to pay for electricity is calculated. By comparing the willingness to pay for electricity with the level and volatility of current European electricity market prices, we were able to determine whether or not large-scale investments in the technology will be feasible. Our methodology allows for a thorough investigation of power-to-gas plants in (future) electricity markets. The general thought that power-to-gas plants can profit from very low and even negative electricity prices is put in perspective.

It is important to remark that some factors that could negatively influence the business case of power-to-gas are not taken into account in this study. First, costs for compressors and hydrogen pipelines are excluded. Including these costs would reduce the long-term willingness to pay for electricity. Second, the electricity prices taken into account in this study are the bare market prices only, excluding taxes such as the German renewable energy surcharge. Including these taxes will drastically lower the amount of hours that the operator will be able to buy electricity and operate the plant.

Other factors can increase the willingness to pay for electricity and thereby improve the power-to-gas business case. No revenue for oxygen and heat is taken into account in our analysis but selling of these by-products might be possible at certain locations and under certain circumstances. Although we took into account the most important future changes in the cost and revenue parameters, more extreme or other changes that would increase the willingness to pay for electricity are very well possible. Some power-to-gas studies (e.g. [5]) assume very high revenues for hydrogen in the mobility sector. This does not seem to be very likely, especially not for large volumes. In case a power-to-gas plant can receive very high revenues for the hydrogen, the short-term willingness to pay will be higher than the real electricity price for almost all hours in the year and the plant will thus practically operate

continuously. In that case, the technology will not serve as a demand side response technology anymore and will not provide flexibility to the power system.

The future of power-to-gas is hard to predict and will depend on the overall layout of the power system. In the long run, the power system will tend towards an equilibrium in which electricity revenues will exactly compensate the costs. Power-to-gas will only play a role in such future power systems if the investment costs reduce significantly, the market value of hydrogen increases strongly and the day-ahead electricity prices remain at the levels that we have recently seen in Denmark and Germany.

In order to foster the development of PtG a number of actions could be taken. Encouraging technological development is pivotal to reduce the costs of PtG production. A crucial action would be to create markets for green hydrogen, which makes it possible to realize a premium in the selling price of hydrogen that is produced in a sustainable way. Finally, keeping the electricity price at a relatively low level is necessary to realize low costs for PtG. An important element in realizing this is to make sure that renewable electricity technologies with low marginal costs set the electricity price during many hours of the year.

## Declarations of interest

None.

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